Security Constrained UCP with Operational and Power Flow Constraints

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Abstract— **An algorithm to solve security constrained unit commitment problem (UCP) with both operational and power flow constraints (PFC) have been proposed to plan a secure and economical hourly generation schedule. This proposed algorithm introduces an efficient unit commitment (UC) approach with PFC that obtains the minimum system operating cost satisfying both unit and network constraints when contingencies are included. In the proposed model repeated optimal power flow for the satisfactory unit combinations for every line removal under given study period has been carried out to obtain UC solutions with both unit and network constraints. The system load demand patterns have been obtained for the test case systems taking into account of the hourly load variations at the load buses by adding Gaussian random noises. In this paper, the proposed algorithm has been applied to obtain UC solutions for IEEE 30, 118 buses and Indian utility practical systems scheduled for 24 hours. The algorithm and simulation are carried through Matlab software and the results obtained are quite encouraging.**

Index Terms—**Unit commitment, Dynamic Programming, Newton Raphson, Lagrangian multiplier, Economic dispatch, optimal power flow, Contingency Analysis.**

I. INTRODUCTION

In power system operation and control, due to variations of load demand and non-storable nature of the electrical energy, given the hourly load forecasting over a period of a day or a week ahead, the system operators should schedule the on/off status, as well as the real power outputs of the generating units to meet the forecasted demand over the time horizon. The resultant UC schedule should minimize the system production cost during the period while simultaneously satisfying the load demand, spinning reserve, ramp constraints and the operational constraints of the individual unit. Scheduling the on and off times of the generating units and minimizing the cost for the hourly generation schedule is the economics to save great deal of money by turning units off (decommiting) when they are not needed. By incorporating UC schedule, the electric utilities may save millions of Dollars per year in the production cost. The system security is still the most important aspect of power system operation and cannot be compromised. Various numerical optimization techniques have been employed to approach the UC problem. Traditional and conventional methodologies such as exhaustive enumeration, priority listing, dynamic programming, integer and linear programming, branch and bound method, lagrangian relaxation, interior point optimization etc. are able to solve UCP with success in varying degree. Carlos E. Murillo-Sanchez and Robert J. Thomas describe a parallel implementation of the Lagrangian relaxation algorithm with variable duplication for the thermal UCP with AC power flow constraints [1]. N.P. Padhy made a comparative study for UCP using hybrid models [2]. Finardi and Silva proposes a model for solving the UCP of hydroelectric generating units [3]. Wei Fan, Xiaohong Guan and Qiaozhu Zhai proposed a new method for scheduling units with ramping constraints [4]. Xiaohong Guan, Sangang Guo and Qiaozhu Zhai discovered how to obtain feasible solution for the security constrained unit commitment (SCUC) problems within the Lagrangian relaxation framework [5]. Qing Xia proposed the optimization problem of UC and economic dispatch with security constraints can be decomposed into two sub problems, one with integer variables and the other with continuous variables [6]. Yong Fu, Mohammad Shahidehpour and Zuyi Li proposes an efficient SCUC approach with ac constraints that obtains the minimum system operating cost while maintaining the security of power systems [7]. Bo Lu and Mohammad Shahidehpour consider network constraints in SCUC and decomposed the problem into master problem for optimizing UC and sub problem for minimizing network violations [8]. Zuyi Li and Mohammad Shahidehpour introduce a SCUC model with emphases on the simultaneous optimization of energy and ancillary services markets [9].

Dynamic programming is used to compute the minimum running cost for a given combination of units according to the enumeration technique for a given load [10-13]. The review of unit commitment problem under regulated system has been given in [15-16] and [17] gives the review of UCP under deregulated market. In every hour all the possible combination of units that satisfies the unit and network constraints are checked by removing one line at a time and proceed until all the lines are removed once. The state which converges for optimal power flow for every line removal is stored and the best combination which gives minimum production cost are selected and stored. Then proceed further until the UC schedule for the entire time horizon is obtained and the total production cost (TC) is obtained and minimized respectively. In a power system, the objective is to find the real and reactive power

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scheduling for each generating unit in such a way to minimize TC. The UC schedule for the generating units considering only the unit constraints may not satisfy the PFC and leads to insecure operation of the network. So to obtain the practical UC solutions the model must consider both the operational and PFC. For secure operation, the UC schedule is obtained by including contingencies in the network. Contingency analysis is performed by removing a line from the power system and checks for PF convergence, if it converges remove the next line and proceed until all the lines are removed once and select the state which converges for every line removal. Repeated OPF for the satisfactory unit combinations under given study period be carried out to obtain UC solutions with unit and network constraints including contingencies. The results obtained using contingency analysis gives a secure UC schedule because they are converged for OPF when any line from the system is removed during the operation. This paper presents the UC schedule for different IEEE bus systems and Indian utility practical system with power flow (PF) constraints and when contingency analysis are done on the system for 24 hours.

II. PROBLEM FORMULATION

UC is an optimization problem of determining the schedule of generating units within a power system with a number of constraints. The objective of the UCP is the minimization of the TC for the commitment schedules is

$$TC = \sum_{i=1}^{N_G} \sum_{t=1}^{T} FC_{it}(P_{Gi}) + ST_{it} + SD_{it} \ \$/hr \tag{1}$$

Where N_G - Total number of generator units

T - Total number of hours considered

$FC_{it}(P_{Gi})$ - Fuel cost at i^{th} hour (\$/h) and represented by an input/output (I/O) curve that is modelled with a polynomial curve (Normally quadratic)

$$FC_{it}\left(P_{Gi}\right) = \alpha_i + \beta_i P_{Gi} + \gamma_i P_{Gi}^2 \quad \$/hr \tag{2}$$

$\gamma_i, \beta_i, \alpha_i$ are the cost coefficient of generator

P_{Gi} - Real Power generated by the ith generator.

ST_{it}, SD_{it} - Start-up cost and start down cost at t^{th} hour (\$/h)

The start up

$$ST_{it} = TS_{it}F_{it} + (1 - e^{(D_{ti}AS_{it})}BS_{it}F_{it} + MS_{it} \tag{3}$$

TS_{it} - Turbines start-up energy at i^{th} hour (MBTu)

F_{it} - Fuel input to the i^{th} generator

D_{it} - Number of hours down at tth hour

AS_{it} - Boiler cool-down coefficient at tth hour

BS_{it} - Boiler start-up energy at tth hour (\$/h)

MS_{it} - Start-up maintenance cost at tth hour (\$/h)

Similarly the start down cost $SD_{it} = kP_{Gi}$ (4)

k is the proportional constant

Subject to the following constraints:

Equality Constraints- Power balance $\sum_{i=1}^{N_G} P_{Gi} = P_{Dt} + P_{Lt}$ (5)

Inequality Constraints: *System spinning reserve constraint*

$$\sum_{i=1}^{N_G} P_{Gi}^{\max} I_{it} \geq P_{Dt} + P_{Rt} \tag{6}$$

Minimum up-time

$$0 < T_{iu} \leq No.of\ hours\ units\ G_i\ has\ been\ on \tag{7}$$

Minimum down-time

$$0 < T_{id} \leq No.of\ hours\ units\ G_i\ has\ been\ off \tag{8}$$

Maximum and minimum output limits on generators

$$P_{Gi}^{\min} \leq P_{Gi} \leq P_{Gi}^{\max} \tag{9}$$

Ramp rate limits for unit generation changes

$$P_{Git} - P_{Gi(t-1)} \leq UR_i \ \ as\ generation\ increases \tag{10}$$

$$P_{Gi(t-1)} - P_{Git} \leq DR_i \ \ as\ generation\ decreases \tag{11}$$

P_{Dt}, P_{Rt}, P_{Lt} - Demand, Spinning reserve, total system losses at t^{th} hour

T_{iu}, T_{id} - Minimum up-time and Minimum down-time in hours

UR_i, DR_i - Ramp-up and Ramp-down rate limit of unit *i* (MW/h)

Power Flow Equality Constraints:

Power balance equations

$$P_{Gi} - P_{Li} - \sum_{j=1}^{N_b} \left|\bar{V}_i\right| \left|\bar{V}_j\right| \left|Y_{ij}\right| \cos\left(\theta_{ij} - \delta_i + \delta_j\right) = 0 \tag{12}$$

$$Q_{Gi} - Q_{Li} + \sum_{j=1}^{N_b} \left|\bar{V}_i\right| \left|\bar{V}_j\right| \left|Y_{ij}\right| \sin\left(\theta_{ij} - \delta_i + \delta_j\right) = 0 \tag{13}$$

Power Flow Inequality Constraints:

$$P_{Gi}^{\min} \leq P_{Gi} \leq P_{Gi}^{\max}, i = 1,........, N_G \tag{14}$$

$$Q_{Gi}^{\min} \leq Q_{Gi} \leq Q_{Gi}^{\max}, i = 1,........, N_G \tag{15}$$

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$$\left|\bar{V}_i\right|^{\min} \leq \left|\bar{V}_i\right| \leq \left|\bar{V}_i\right|^{\max}, \; i = 1,\ldots\ldots, N_L \qquad (16)$$

$$\phi_i^{\min} \leq \phi_i \leq \phi_i^{\max} \qquad (17)$$

$$MVA \; f_{ij} \leq MVA \; f_{ij}^{\max}, \; i = 1,\ldots\ldots, N_{TL} \qquad (18)$$

N_b, N_G - Number of total buses, number of generator buses

N_L, N_{TL} - Number of load buses, number of transmission lines

$P_{Gi}^{\min}, P_{Gi}^{\max}$ - Limits of real power allowed at generator i.

$Q_{Gi}^{\min}, Q_{Gi}^{\max}$ - Limits of reactive power allowed at generator i.

P_{Gi}, Q_{Gi} - Real and reactive power generation at bus *i*

P_{Li}, Q_{Li} - Active and reactive power loss at bus *i*

$|V_i|$, δ_i - Voltage magnitude, Voltage angle at bus *i*

Y_{ij} - ij^{th} elements of Y-bus matrix

MVA f_{ij} - Apparent power flow from bus *i* to bus *j*

MVA $f_{ij}^{\max}$ - Maximum rating of transmission line connecting bus *i* and *j*.

III. Implementation of contingency analysis based UCP with operational and power flow constraints

1. Initialize the unit characteristics for the N unit system with system constraints.
2. Find all the available states that satisfy the load demand for 24 hours. Each state corresponds to the "ON" and "OFF" conditions of the generator units and represented as 1 and 0.
3. Calculate the transitional generation cost for the states satisfying the system constraints along with contingencies on their transit from the present stage to the succeeding stage with the help of following steps:

For each satisfying state perform contingency analysis by removing one line from the system and carry out the optimal power flow solution using a hybrid Lagrangian multiplier and Newton Raphson power flow algorithms. Perform contingency analysis for each satisfying state repeatedly until all the lines are removed once except the lines which are connected only either to the load bus or generator bus and carry out optimal power flow for every contingency for that state. Prepare the data base for the system including line data, bus data, generator data and tap setting of the transformers.

a. Form Y_{bus} using line resistance, reactance, and shunt elements [14].

Obtain the power flow solution for the states got from step 2 using Newton-Raphson method for power flow subject to the power-flow equations.

b. Calculate the B_{mn} loss coefficients using V and δ obtained from the PF solution. From the power flow solution, the voltage magnitude and phase angle of all buses are determined. The total transmission power loss including B_{mn} is given by

$$P_L = \sum_{i=1}^{N_G}\sum_{j=1}^{N_G} P_i B_{ij} P_j + \sum_{i=1}^{N_G} B_{0i} P_i + B_{00} \qquad (19)$$

c. After getting the loss coefficient perform economic dispatch i.e., the power generated in each 'ON' generator unit using Lagrangian multiplier method.

d. Read the total demand, cost characteristics and MW limits along with loss co-efficients. The condition for optimum dispatch

$$\frac{dC_i}{dP_{Gi}} + \lambda \frac{\partial P_L}{\partial P_{Gi}} = \lambda, \quad i = 1 \ldots N_G \qquad (20)$$

$$\sum_{i=1}^{N_G} P_{Gi} = P_{Dt} + P_{Lt} \qquad (21)$$

Equation 19 can be written as

$$\left(\frac{1}{1 - \frac{\partial P_L}{\partial P_{Gi}}}\right)\frac{dC_i}{dP_{Gi}} = \lambda, \quad i = 1, \ldots, N_G \qquad (22)$$

$$L_i \frac{dC_i}{dP_{Gi}} = \lambda, \quad i = 1, \ldots, N_G \qquad (23)$$

where L_i is the penalty factor of plant.

f. For an estimated value of λ, P_{Gi} are found from the cost quadratic function.

$$P_{Gi}^{(k)} = \frac{\left(\lambda^{(k)}(1 - B_{0i}) - \beta_i - 2\lambda^{(k)}\sum_{j \neq i} B_{ij} P_{Gj}^{(k)}\right)}{2\left(\gamma_i + \lambda^{(k)} B_{ii}\right)} \qquad (24)$$

$$\Delta\lambda^{(k)} = \frac{\Delta P^{(k)}}{\sum \left(\frac{dP_{Gi}}{d\lambda}\right)^{(k)}} \qquad (25)$$

$$\lambda^{(k+1)} = \lambda^{(k)} + \Delta\lambda^{(k)}$$

$$\Delta P^{(k)} = P_{Dt} + P_{Lt}^{(k)} - \sum_{i=1}^{N_G} P_{Gi}^{(k)}$$

g. Check the slack bus power generated from the cost quadratic function and the slack bus power obtained from the power flow solution.

h. If they lie with in a tolerance limit say 0.001, do the load flow with the P_{Gi} obtained from the economic dispatch and determine the generation cost using the cost characteristic equation

$$C_i = \alpha_i + \beta_i P_{Gi} + \gamma_i P_{Gi}^2 \qquad (28)$$

If they are not with in the tolerance limit, then with the power generation obtained from economic dispatch using cost quadratic equation is given as the P specified in the load flow analysis for the next iteration. Once again the losses can be obtained from the new power flow solution and repeat the economic dispatch.

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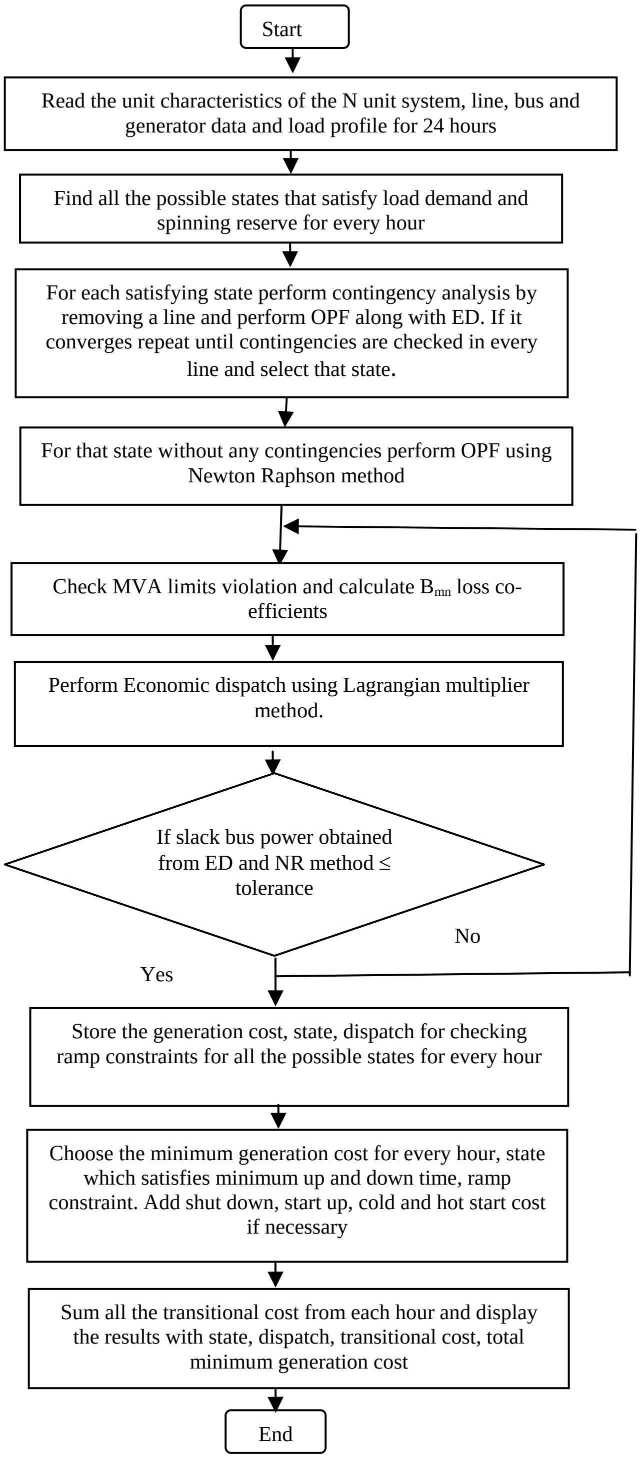

Figure1 Flow chart for the proposed algorithm

The state which converges for power flow when all the lines are removed once from the system is selected. For that state perform power flow and economic dispatch without any contingencies in the system and store the transitional cost.

j. The same procedure is followed for all the states that satisfy the load demand and spinning reserve constraints for that hour. Repeat the above steps for 24 hours with the generated load profile and tabulate all the transitional cost of the satisfying states for each stage.

k. Choose the state with minimum transitional cost for each stage that satisfies the unit constraints. Calculate TC by the summation of all the minimum transitional cost obtained between each stage and print the results. The flow chart for this algorithm has been given in Figure 1.

IV. SIMULATION AND RESULTS

Three case studies consisting of an IEEE 30, 118 bus systems and Indian utility 75 bus system have been considered to illustrate the performance of UC schedule with contingency analysis in the network. The UC schedule obtained considering contingency analysis is very realistic as it has the capability to withstand when contingency exists in a particular line. The contingency analysis is not performed on the lines which are completely dedicated for generating and supplying the loads. The unit combination which satisfies the load demand and spinning reserve are allowed to perform OPF for every contingency and the unit combination for which OPF converges for every line removal is selected. For that unit combination OPF is performed without considering any contingencies and store the dispatch and transitional cost. The commitment schedules and the transitional cost at each stage with contingency analysis, with and without power flow constraints (PFC) for the above case studies have been tabulated from Table 1 to 3. Loads at different buses are assumed to be variable and have been generated using Gaussian random noise function for the twenty four hours during power flow simulations because in practice the loads do not vary uniformly.

Case a. IEEE 30 bus system

The IEEE 30 bus system has six generating units and the characteristics of generators, unit constraints and the hourly load distribution over the 24 hour horizon. The network topology and the test data for the IEEE 30 bus system are given in http:// www.ee.washington.edu/research/pstca. For every hour, all the possible combinations that satisfy the load demand and spinning reserve constraints are selected and these states are allowed to perform OPF for all the possible contingencies that can happen in that network. If the state converges for OPF for every line removal, then select that state and perform OPF without any contingencies and store that state. Similarly all the states that satisfy OPF for every contingency in the system and demand on that hour are stored. This procedure has to continue for the specified time horizon. Select the state that possess minimum cost and satisfies the unit constraints for the entire time horizon. Finally the complete unit commitment schedule with minimum TC has been obtained. The TC obtained by considering contingency in the network are 916.2 $/day more than the generation cost obtained without PFC and 512.5 $/day more than the generation cost obtained with PFC. UC schedule without PFC and performing contingency analysis may not be

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practical, since the states must include the system network losses and also converge for optimal power flow. This is the reason for the cost being minimum when power flow constraints and contingency analysis are not considered. The transitional generation cost for every hour have been compared and plotted with CA, with and without PFC in Figure 2.

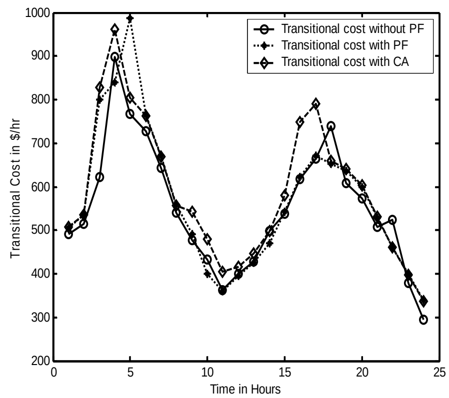

Figure 2. Transitional cost for IEEE 30 bus

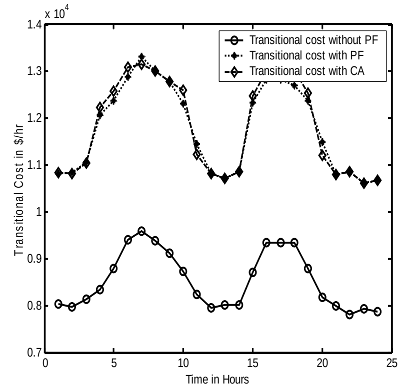

Figure 3. Transitional cost for IEEE 118 bus

Table 1. IEEE 30 bus UC schedule

Period	Load	UC without PFC	Trans cost	UC with PFC	Trans Cost	Security Constrained UC	Trans cost
1	166	101101	492.3680	101101	506.0666	101101	506.5560
2	196	101101	514.4198	101101	535.2034	101101	536.4296
3	229	101101	623.0319	111101	799.0942	101111	828.0507
4	267	111101	898.2148	111001	838.9670	111110	961.8205
5	283.4	111101	766.8436	111011	987.8135	111110	804.9445
6	272	111101	728.0110	111011	765.0130	111110	762.8829
7	246	111101	642.2775	111011	670.6727	111110	669.4243
8	213	111101	539.1919	111011	558.4164	111110	557.2563
9	192	111101	476.9293	111011	491.5142	111100	542.7611
10	161	110101	432.1891	111011	398.9967	111000	479.9059
11	147	110101	363.5154	111011	359.6488	110000	404.7152
12	160	110101	399.3866	111011	396.1338	110000	415.5276
13	170	110101	427.6901	111011	425.1014	110000	447.9513
14	185	110100	497.5949	111011	469.9788	110000	498.2986
15	208	110100	538.8728	111011	542.1670	110000	579.6063
16	232	110100	616.7335	111011	621.9727	111000	748.7215
17	246	110100	663.7953	111011	670.6739	111001	791.2400
18	241	111100	738.3682	111011	653.0992	111001	659.6339

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19	236	111100	609.1311	111011	635.7233	111001	641.7818
20	225	111100	573.9276	111011	598.2173	111001	602.9092
21	204	111100	508.6984	111011	529.3179	111001	531.0425
22	182	111000	524.2561	111011	460.8624	111001	460.6676
23	161	111000	378.1085	111011	398.9961	111001	397.0433
24	131	111000	295.4216	111010	338.9695	111000	335.9958
Total Minimum cost in $ / day			13248.9		13652.6		14165.1

Table 2. IEEE 118 bus UC schedule

Period	Load	UC without PFC	Trans cost	UC with PFC	Trans cost	Security Constrained UC	Trans cost
1	3170	1111101111111101100	8026.0	1111101011111111101	10820	1111101011111111110	10833
2	3200	1111101111111101100	7978.8	1111101011111111101	10839	1111101011111111110	10809
3	3250	1111101111111101100	8134.8	1111101011111111101	11062	1111101011111111110	11043
4	3300	1111101011111101100	8334.4	1111101011111101100	12070	1111101011111111110	12226
5	3460	1111101011111101100	8791.1	1111101011111101100	12367	1111101011111111110	12578
6	3640	1111101011111101100	9400.9	1111101011111101100	12890	1111001011111101110	13092
7	3686	1111001011111101100	9595.8	1111001011111101110	13319	1111001011111101110	13154
8	3640	1111001011111101100	9386.8	1111001011111101110	13010	1111001011111101110	13010
9	3560	1111001011111101100	9116.9	1111001011111101110	12775	1111001011111101110	12775
10	3440	1111001011111101100	8719.5	1111001011111101100	12307	1111001011111111110	12603
11	3250	1111001011111111100	8229.8	1111101011111111110	11449	1111101011111111110	11223
12	3200	1111001011111111100	7960.6	1111101011111111110	10809	1111101011111111110	10809
13	3175	1111001011111111110	8016.6	1111101011111111110	10707	1111101011111111110	10707
14	3210	1111001011111111110	8012.0	1111101011111111110	10850	1111101011111111110	10850
15	3420	1111001011111101110	8703.8	1111101011111101100	12326	1111101011111111110	12483
16	3620	1111001011111101110	9337.9	1111101011111101100	12827	1111101011111101110	13013
17	3620	1111001011111101110	9337.9	1111101011111101100	12827	1111101011111101110	12983
18	3580	1111001011111111100	9333.2	1111101011111101100	12702	1111001011111111110	13024
19	3460	1111001011111111100	8791.4	1111101011111101100	12367	1111001011111111110	12539
20	3270	1111001011111111100	8179.7	1111001011111111111	11483	1111001011111111111	11205
21	3210	1111001011111111100	7991.7	1111001011111101111	10796	1111001011111101111	10796
22	3153	1111001011111101100	7813.8	1111101011111101110	10855	1111101011111101110	10855
23	3148	1111001011111101110	7927.0	1111101011111101110	10608	1111101011111101110	10608
24	3166	1111001011111101110	7869.3	1111101011111101110	10673	1111101011111101110	10673
Total Minimum cost in $ / day 204989.5					282737.1		283889.1

Case b. IEEE 118 bus system.

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The proposed algorithm has been applied to IEEE 118 bus with 19 generating units. The network topology and the test data for the IEEE 118 bus system has been taken from http://www.ee.washington.edu/research/pstca.UC schedules for an IEEE 118 bus with CA, with and without PFC are given in Table 2. The total generation cost obtained by considering contingency in the network are 78899.6 $/day more than the generation cost obtained without power flow constraints and 1152 $/day more than the generation cost obtained with power flow constraints. The transitional generation cost for every hour have been compared and plotted with CA, with and without power flow constraints are given in Figure 3.

Table 3. UP 75 bus UC schedule

Period	Load	UC without PFC	Trans cost	UC with PFC	Trans Cost	UC with CA	Trans cost
1	3352	111110111111111	3845.1	111110111111111	4090.9	111111111101111	4113.1
2	3384	111110111101111	3918.0	111110111101111	4170.1	111111111101111	4117.4
3	3437	111110111101111	3954.3	111110111101111	4213.9	111111110101111	4296.1
4	3489	111110011101111	4091.7	111110011101111	4355.5	111111110101111	4376.8
5	3659	111110011101111	4332.9	111110011101111	4626.5	111111110001111	4772.5
6	3849	111110011101111	4669.0	111111011101111	5072.8	111111110011111	5217.8
7	3898.1	111110011101111	4755.6	111111011111111	5225.6	111111110011111	5131.7
8	3849	111110011101111	4669.0	111111011111111	4954.0	111111110011111	5037.8
9	3764	111110011101111	4517.3	111111011111111	4808.3	111111111011111	4935.0
10	3637	111100011101111	4351.6	111111011111111	4565.6	111111111011111	4575.7
11	3437	111100011101111	3956.2	111111011101111	4264.1	111111111111111	4476.6
12	3384	111100001101111	3925.2	111111011101111	4116.7	111111111101111	4169.4
13	3357	111100001101111	3820.1	111111011101111	4069.2	111111111101111	4069.9
14	3394	111100001101111	3882.0	111111011101111	4136.1	111111110101111	4219.4
15	3616	111100001101111	4264.0	111111001101111	4606.0	111111110101111	4595.1
16	3828	111100001101111	4638.6	111111001111111	5098.4	111111110101111	4997.5
17	3828	111100001101111	4638.6	111111001111111	4918.4	111111110101111	4997.5
18	3786	111101001101111	4677.7	111110001111111	4874.8	111111110101111	4917.0
19	3659	111101001101111	4337.8	111110001111111	4609.9	111111110001111	4772.5
20	3458	111100001101111	4020.1	111110001111111	4248.0	111111110001111	4316.6
21	3394	111100001101111	3882.0	111110001111111	4134.5	111111110001111	4199.6
22	3334	111100001001111	3864.4	111111001111111	4141.0	111111110001111	4090.7
23	3329	111100001001111	3771.1	111111001111111	4019.2	111111111001111	4139.1
24	3348	111100001001111	3802.8	111110001111111	4084.0	111111111001111	4059.4
Total Minimum cost			100584.8 $/day		107403.5$/day		108594.4$/day

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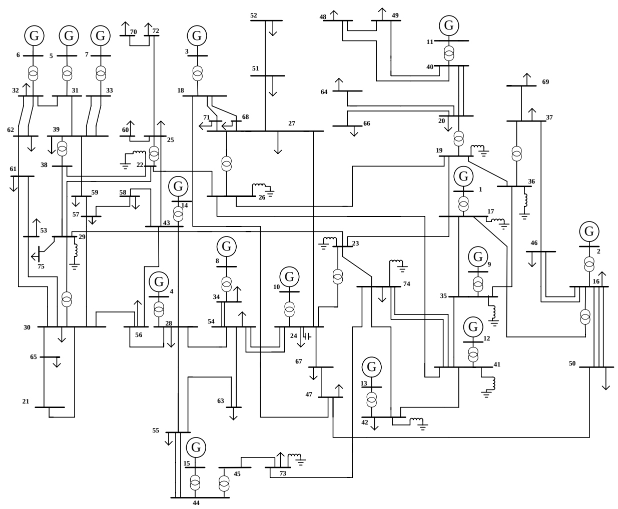

Figure 4. One line diagram of Indian utility system

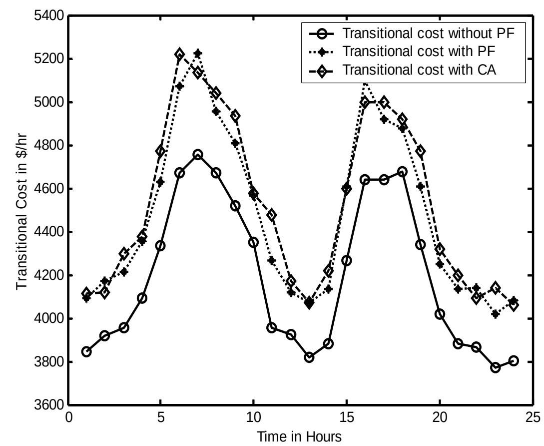

Figure 5. Transitional Cost of Indian Utility System

Case c. Indian Utility (Uttar Pradesh State) 75 bus system

The 75-bus Uttar Pradesh State Electricity Board (UPSEB) Indian Utility system with fifteen generating units is shown in Figure 4. The data in per unit (p.u) is on 100 MVA base. UC schedules for the 75 bus system with CA, with and without power flow constraint are given in Table 3. The total generation cost obtained by considering contingency in the network are 8009.6 $/day more than the generation cost obtained without PFC and 1190.9 $/day more than the generation cost obtained with PFC. The solution results in this study indicate that the proposed algorithm is applicable to the day-ahead UC calculation of large scale power systems. The transitional generation cost for every hour have been compared and plotted with CA, with and without power flow constraints are given in Figure 5. The platform used for the implementation of this proposed approach is on INTEL[R], Pentium [R] 4 CPU 1.8 GHz, 256 MB of RAM and simulated in the MATLAB environment. The solution results in this study indicate that the proposed algorithm is applicable to the day-ahead UC calculation of large scale power systems.

V. CONCLUSION

This paper presents an approach to solve security constrained UCP by accommodating both unit and network constraints. This algorithm would give realistic results as the entire unit and network constraints are included. The commitment schedule holds well even if there is any contingency in any of the lines in the network as the selected unit combination has been converged for OPF for every contingency occurred in the system. The security constrained UC schedule has been compared with the commitment schedule obtained by incorporating both network and unit constraints, also with the commitment schedule obtained without incorporating network constraints. Since exhaustive enumeration technique is used, it guarantees the optimality of the solution. The effectiveness of this method has been demonstrated on an IEEE 30, 118 buses and on Indian utility system and may also be extended to large systems. The results achieved are quite encouraging and indicate the viability of the proposed technique to deal with future UC problems.

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